MARKET PROCEDURE: Maximum Reserve Capacity Price

VERSION 5

ELECTRICITY INDUSTRY ACT 2004

ELECTRICITY INDUSTRY
(WHOLESALE ELECTRICITY MARKET)
REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

COMMENCEMENT:

This Market Procedure took effect from 8:00am (WST) on the same date as the Wholesale Electricity Market Rules.

VERSION HISTORY

VERSION	EFFECTIVE DATE	NOTES
1	13 October 2008	Market Procedure for Determination of the Maximum Reserve Capacity Price resulting from PC_2008_06
2	4 December 2008	Amended Market Procedure for Determination of the Maximum Reserve Capacity Price resulting from PC_2008_14
3	1 April 2010	Amendments to the Procedure resulting from Procedure Change Proposal PC_2009_12
4	11 October 2010	Amendments to the Procedure resulting from Procedure Change Proposal PC_2010_04
5	24 October 2011	Amendments to the Procedure resulting from Procedure Change Proposal PC_2011_06

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1 PROCEDURE FOR DETERMINING THE MAXIMUM RESERVE CAPACITY PRICE

1.1 Relationship with the Market Rules

1.1.1 This Procedure should be read in conjunction with clause 4.16 of the Wholesale Electricity Market (WEM) Rules (Market Rules) and is made in accordance with clause 4.16.3 of the Market Rules.

1.1.2 References to particular Market Rules within this Procedure in bold and square brackets **[MR XX}** are current as of 17 October 2011. These references are included for convenience only, and are not part of this Procedure.

1.2 Purpose

1.2.1 This Procedure describes the methodology that the IMO must use and the steps that the IMO must undertake in determining the Maximum Reserve Capacity Price in each Reserve Capacity Cycle.

1.3 Application

1.3.1 This procedure applies to:

(a) The IMO in conducting any review of the Maximum Reserve Capacity Price, including necessary consultations **[MR4.16.3]**; and

(b) Western Power in developing estimates of the costs associated with connecting a notional Power Station to the 330 kV transmission systems.

1.4 Associated Market Procedures

1.4.1 There are no other Market Procedures associated with this Procedure.

1.5 Interpretation

1.5.1 In this Procedure the conventions specified in clauses 1.3 - 1.5 of the Market Rules apply. The following additional clarifications are noted for the purposes of this Procedure:

(a) “Access Offer” has the same meaning as in the *Electricity Networks Access Code 2004*.

(b) “Contribution Policy” has the same meaning as in the *Electricity Networks Access Code 2004*.

(c) "Declared Sent Out Capacity" has the same meaning as in the *Electricity Networks Access Code 2004*.

(d) "Power Station" means the theoretical power station upon which the Maximum Reserve Capacity Price is based, described in step 2.1.

(e) "Total Transmission Costs" are the costs to directly connect a generator to the transmission network and to augment the shared transmission network to accommodate the capacity of that generator, which are estimated in step 2.4.

2 PROCEDURE STEPS

This section outlines the methodology the IMO must apply in determining the Maximum Reserve Capacity Price and the procedures steps the IMO must follow in conducting its annual review of the Maximum Reserve Capacity Price.

2.1 Definition of Power Station

2.1.1 The Power Station upon which the Maximum Reserve Capacity Price is based must:

(a) be representative of an industry standard liquid-fuelled Open Cycle Gas Turbine (OCGT) power station;

(b) have a nominal nameplate capacity of 160 MW prior to the addition of any inlet cooling system;

(c) operate on distillate as its fuel source;

(d) have a capacity factor of 2%;

(e) include low Nitrous Oxide (NOx) burners or associated technologies as would be required to demonstrate good practice in power station development; and

(f) include an inlet air cooling system and water receival and storage facilities to allow 14 hours of continuous operation, where in the opinion of the IMO this would be cost effective.

2.2 Scope of the Factors to Maximum Reserve Capacity Price

2.2.1 The Maximum Reserve Capacity Price must include all reasonable costs expected to be incurred in the development of the Power Station, which must include estimation and determination of:

(a) Power Station balance of plant costs, which are those other ancillary and infrastructure costs that would normally be experienced when developing a project of this nature;

(b) land costs;

(c) costs associated with the development of liquid fuel storage and handling facilities;

(d) costs associated with the connection of the Power Station to the bulk transmission system;

(e) allowances for legal costs, insurance costs, financing costs and environmental approval costs;

(f) reasonable allowance for a contingency margin; and

(g) estimates of fixed operating and maintenance costs for the Power Station, fuel handling facilities and the transmission connection components.

2.3 Development of Costs for the Power Station

2.3.1 The IMO must engage a consultant to provide:

(a) an estimate of the costs associated with engineering, procurement and construction of the Power Station as at April in Year 3 of the Reserve Capacity Cycle;

(b) a summary of any escalation factors used in the determination; and

(c) likely output at 41°C which will take into account available turbine and inlet cooling technology, likely humidity conditions and any other relevant factors, which represents the expected Capacity Credit allocation for the Power Station.

2.3.2 The Power Station costs must be determined with specific reference to the use of actual project-related data and must take into account the specific conditions under which the Power Station will be developed. This may include direct reference to:

(a) Existing power stations, or power station projects under development, in Australia and more particularly Western Australia.

(b) Worldwide demand for gas turbine engines for power stations.

(c) The engineering, design and construction, environment and cost factors in Western Australia.

(d) The level of economic activity at the state, national and international level.

2.3.3 Development of the Power Station costs must include components for the gas turbine engines, and all Balance of Plant costs that would normally be applicable to such a Power Station. This must include, but will not be limited to the following items:

(a) Civil Works.

(b) Mechanical Works.

(c) Electrical Works.

(d) Buildings and Structures.

(e) Engineering and Plant Setup.

(f) Miscellaneous and other costs.

(g) Communications and Control equipment.

(h) Commissioning Costs.

2.4 Transmission Connection Works

2.4.1 Western Power must provide an estimate of the Total Transmission Costs in accordance with the methodology herein to connect the generator and deliver the output to loads consistent with the relevant planning criteria in the Technical Rules.

The estimated Total Transmission Costs must be derived from capital contributions (either paid historically or expected to be paid to Western Power under Access Offers and Western Power's Contribution Policy as approved by the ERA) only for generators that are capable of being gas or liquid fuelled. The calculation must exclude any facility where, in the opinion of Western Power:

- the significant driver for the location of the facility is the access to source energy (fuel or renewable) or the need to embed the generation with a load (electrical or heat). For clarity, this includes but is not limited to coal, renewable and embedded (including waste heat capture) generators;

- the facility is connected on a shared distribution feeder; or

- the capital contribution does not relate to a significant increase in the Declared Sent Out Capacity associated with the facility.

Western Power may seek clarification from the IMO with regard to the inclusion or exclusion of specific projects in line with the above criteria.

For the purpose of the calculation, the un-escalated dollar value of the capital contribution for a facility must be attributed to the Capacity Year for which the facility is first assigned, or expected to be assigned, Capacity Credits and must be assumed to be in the dollars as at 1 October of that Capacity Year.

The estimate of Total Transmission Costs must use the following process:

(a) Historic and forecast capital contribution data must be collated for all works required to connect relevant generators to the transmission network including:

- all transmission connection works required to connect from the high voltage (HV) bus bar (or in the absence of a HV bus bar, the HV circuit breaker or terminals of generator step-up transformers) to the shared transmission network (including all miscellaneous costs such as procuring land easements etc.); and

- all transmission works to reinforce the shared transmission network where required in accordance with the Access Code and the Technical Rules.

Capital contributions paid or forecast to be paid to Western Power may not have been calculated to cover the cost of all connection assets required to connect from the HV bus bar (or in the absence of a HV bus bar, the HV circuit breaker or terminals of generator step-up transformers) to the shared transmission network. In this case, Western Power must identify the connection assets that have not been covered in the capital contribution and must add to the capital contribution its estimate of the cost to construct the assets based on:

- the actual length and route of transmission or distribution lines;

- the actual line voltage;

- sufficient capacity to allow for transmission of the Certified Reserve Capacity (actual or anticipated) of the facility;

- the terrain described in step 2.4.2(e); and

- an estimate of the easement costs described in step 2.4.2(h).

(b) For years for which no historic capital contribution data or Access Offers for relevant generators are available, a connection cost must be calculated on the basis defined in step 2.4.2. For this purpose it is assumed that the costs of the works described in step 2.4.2 are fully borne by the connecting generator and the cost to reinforce the shared transmission network is assumed to be zero.

(c) The sum of connection costs for each Capacity Year must be divided by the sum of the generators' Certified Reserve Capacity to provide an "average per unit capacity" connection cost for each year. The quantity of Certified Reserve Capacity for a facility will be the level most recently assigned to that facility that is attributable to that capital contribution. Western Power may consult with the IMO to confirm the appropriate quantity of Certified Reserve Capacity for each facility.

The average per unit capacity cost must be determined for the "Latest Offer Year", being the year which is the later of:

- the latest Capacity Year for which a capital contribution has been determined or an Access Offer has been made; and

- the Capacity Year commencing in Year 1 of the relevant Reserve Capacity Cycle.

The average per unit capacity cost must also be determined for each of the 4 Capacity Years immediately preceding the Latest Offer Year.

(d) The five average per unit capacity costs determined in (c) must be escalated to 1 April of Year 3 of the relevant Reserve Capacity Cycle.

The basis of escalation must be the average change over 5 years in the estimates calculated consistent with step 2.4.2. Where 5 years of data calculated on a common basis is not available the escalation rate must be averaged over the period for which equivalent data is available.

(e) The escalated per unit capacity costs from (d) must be multiplied by the corresponding weighting factors in the table below:

Year	Weighting
Latest Offer Year	7
Latest Offer Year - 1	5
Latest Offer Year - 2	3

Year	Weighting
Latest Offer Year - 3	1
Latest Offer Year – 4	1

The sum of the 5 years of weighted, escalated, average per unit capacity costs for the 5 years under consideration must be divided by 17 to provide a weighted escalated average per unit connection cost.

(f) The weighted escalated average per unit cost must be scaled up by 15% as an allowance for forecasting error margin to provide the forecast connection cost.

(g) Western Power must appoint a suitable auditor to review the application of the process in step 2.4.1 on an independent and confidential basis. Western Power must provide the advice of the auditor to the IMO together with its estimate of Total Connection Costs, and the IMO must publish the auditor's advice on the Market Web-site.

2.4.2 For the purposes outlined in step 2.4.1, Western Power must also estimate the cost of transmission connection works required to connect from the HV bus bar to the shared transmission network using the following process:

(a) The capital cost (procurement, installation and commissioning, excluding land cost) of a generic, industry standard 330kV substation that facilitates the connection of the Power Station must be estimated.

(b) The estimate must include all the components and costs associated with a standard substation.

(c) The estimated cost must be based on a generic three breaker mesh substation configured in a breaker and a half arrangement.

(d) It must be assumed that the substation is located adjacent to an existing transmission line and include an allowance for 2km of 330kV overhead single circuit line to the power station that will have one road crossing.

(e) It must be assumed that the transmission connection to the Power Station will be located on 50% flat - 50% undulating land, 50% rural - 50% urban location and that there will be no unforeseen environmental or civil costs associated with the development.

(f) It must be assumed that the connection of the substation into the existing transmission line is turn-in, turn-out and is based on the most economical (i.e. least cost) solution. It must be assumed that the existing transmission line will not require modification to allow the connection with the exception of one new tower located at the substation to allow a point of connection.

(g) Costs associated with any staging works must not be considered.

(h) Shallow connection easement costs will be included and must be estimated and provided by the IMO.

2.5 Fixed Operating and Maintenance Costs

2.5.1 The IMO must determine Fixed Operating and Maintenance (O&M) costs for the Power Station and the associated transmission connection works. The IMO may engage a consultant to assist the IMO in this process.

2.5.2 The Fixed O&M costs may be separated into those costs associated with the Power Station, those costs associated with the transmission connection infrastructure and any other major components that are considered likely to be of sufficient magnitude so as to require separate determination.

2.5.3 Fixed O&M costs must also include:

(a) fixed network access and/or ongoing charges, which are to be provided by Western Power; and

(b) an estimate of annual insurance costs as at 1 October in Year 3 of the relevant Reserve Capacity Cycle in respect of power station asset replacement, business interruption and public and products liability insurance as required under network access arrangements with Western Power.

2.5.4 To assist in the computation of annualised Fixed O&M costs, the costs associated with each major component will be presented for each 5 year period up to 60 years.

2.5.5 The Fixed O&M costs must be converted into an annualised Fixed O&M cost as required under the determination methodology in section 1.14.

2.5.6 Fixed O&M costs must be determined as at 1 October in Year 3 of the Reserve Capacity Cycle. Where Fixed O&M costs have been determined at a different date, those costs must be escalated using the following escalation factors which must be applied to relevant components within the Fixed O&M cost:

(a) a Generation O&M Cost escalation factor for Generation O&M costs;

(b) a Labour cost escalation factor for transmission and switchyard O&M costs; and

(c) CPI for fixed network access and/or ongoing charges determined with regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.

2.6 Fixed Fuel Cost

2.6.1 The IMO must engage a consultant to determine an estimate of the costs for the Liquid Fuel storage and handling facilities including:

(a) A fuel tank of 1,000 t (nominal) capacity including foundations and spillage bund.

(b) Facilities to receive fuel from road tankers.

(c) All associated pipework, pumping and control equipment.

2.6.2 The estimate should be based on the following assumptions:

(a) Land is available for use and all appropriate permits and approvals for both the power station and the use of liquid fuel have been received.

(b) Any costing components that may be time-varying in nature must be disclosed by the IMO. Such components might be the cost of the liquid fuel, which will vary over time and as a function of exchange rates etc.

2.6.3 The costing must only reflect fixed costs associated with the Fixed Fuel Cost (FFC) component and must include an allowance to initially supply fuel sufficient to allow for the Power Station to operate for 14 hours at maximum capacity.

2.6.4 Fixed Fuel Costs (FFC) must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where Fixed Fuel Costs have been determined at a different date, those costs must be escalated using the annual CPI cost escalation factor determined in step 2.5.6(c).

2.7 Land Costs

2.7.1 The IMO must retain Landgate under a consultancy agreement each year to provide valuations on parcels of industrial land. The regions for which the analysis is to be conducted will include:

(a) Collie Region

(b) Kemerton Industrial Park Region

(c) Pinjar Region

(d) Kwinana Region

(e) North Country Region

(f) Kalgoorlie Region

These areas represent the regions within the South West interconnected system (SWIS) where generation projects are most likely to be proposed and should provide a broad cross-section of options. The IMO may include additional locations if it considers appropriate.

2.7.2 The IMO must contract with Landgate to conduct the valuations on the same land parcel size, so as to provide a consistent method of valuing the cost of purchase of the land. The IMO will provide an indication as to the size of land required, which should be limited to the following options:

(a) One 3ha parcel of land in an industrial area of a standard size with consideration given to any requirements for a buffer zone in that specific location. Where the minimum land size available in any specific location is greater than 3ha, for the purpose of calculating the land cost for that specific location, the minimum available land size at that location shall be used.

(b) The summation of multiple smaller parcels of land as appropriate to meet the requirements above.

2.7.3 Where the IMO is unable to contract with Landgate to provide the valuations described in steps 2.7.1 and 2.7.2, the IMO may seek valuations from an alternative provider of similar services.

2.7.4 The IMO must determine the average cost of the land parcels described in steps 2.7.1 and 2.7.2.

2.7.5 The average Land Cost, LC, must be determined as at April in Year 3 of the Reserve Capacity Cycle. Where the average Land Cost has been determined at a different date this cost must be escalated using the CPI escalation factor determined in step 2.5.6(c).

2.8 Legal, Financing, Insurance, Approvals, Other Costs and Contingencies (margin M)

2.8.1 The IMO must engage a consultant to determine the value of margin M, which shall constitute the following costs associated with the development of the Power Station project:

(a) legal costs associated with the design and construction of the power station.

(b) financing costs associated with equity raising.

(c) insurance costs associated with the project development phase;

(d) approval costs including environmental consultancies and approvals, and local, state and federal licensing, planning and approval costs;

(e) other costsreasonably incurred in the design and management of the power station construction; and

(f) contingency costs.

2.9 Weighted Average Cost of Capital (WACC)

2.9.1 The IMO must determine the cost of capital to be applied to various costing components of the Maximum Reserve Capacity Price. This cost of capital must be an appropriate WACC for the generic Power Station project considered, where that project is assumed to receive Capacity Credits through the Reserve Capacity Auction and be eligible to receive a Long-Term Special Price Arrangement through the Reserve Capacity Mechanism.

2.9.2 The WACC will be applied directly:

(a) in the annualisation process used to convert the Power Station project capital cost into an annualised capital cost; and

(b) to account for the cost of capital in the time period between when the Reserve Capacity Auction is held (i.e. when capital is raised), and when the payment stream is expected to be realised. To maintain computational simplicity it is assumed that the total investment cost of the generic power station will be incurred in even incremental amounts over the 12 month period immediately preceding the first Reserve Capacity Year. As a result the effective compensation period for the total investment cost for the generic power station will be six months as detailed in the CAPCOST formula in step 2.10.1.

2.9.3 The methodology adopted by the IMO to determine the WACC will involve a number of components that require review. These components are classed as those which require review annually (called Annual components) and those structural components of the WACC which require review less frequently (called 5 Yearly components) as detailed in step 2.9.8.

2.9.4 In determining the WACC, the IMO:

(a) must annually review and determine values for the Annual components; and

(b) may review and determine values for the 5 Yearly components that differ from those in step 2.9.8 if, in the IMO's opinion, a significant economic event has occurred since undertaking the last 5 yearly review of the Maximum Reserve Capacity Price in accordance with clause 4.16.9 of the Market Rules.

2.9.5 The IMO may engage a consultant to assist the IMO in reviewing the CAPM components of the WACC listed under step 2.9.8.

2.9.6 The IMO shall compute the WACC on the following basis:

(a) The WACC shall use the Capital Asset Pricing Model (CAPM) as the basis for calculating the return to equity.

(b) The WACC shall be computed on a Pre-Tax basis.

(c) The WACC shall use the standard Officer WACC method as the basis of calculation.

2.9.7 The pre-tax real Officer WACC shall be calculated using the following formulae:

$$WACC_{real} = \left(\frac{(1 + WACC_{nominal})}{(1 + i)} \right) - 1 \text{ and}$$

$$WACC_{nominal} = \frac{1}{(1 - t(1 - \gamma))} R_e \frac{E}{V} + R_d \frac{D}{V}$$

Where:

(a) R_e is the nominal return on equity (determined using the Capital Asset Pricing Model) and is calculated as:

$$R_e = R_f + \beta_e \times MRP$$

Where:
R_f is the nominal risk free rate for the Capacity Year;
β_e is the equity beta; and
MRP is the market risk premium.

(b) R_d is the nominal return on debt and is calculated as:

$$R_d = R_f + DM$$

Where:
R_f is the nominal risk free rate for the Capacity Year;

DM is the debt margin, which is calculated as the sum of the debt risk premium (DRP) and debt issuance cost (d).

(c) t is the benchmark rate of corporate income taxation, established at either an estimated effective rate or a value of the statutory taxation rate;

(d) γ is the value of franking credits;

(e) E/V is the market value of equity as a proportion of the market value of total assets;

(f) D/V is the market value of debt as a proportion of the market value of total assets;

(g) The nominal risk free rate, R_f, for a Capacity Year is the rate determined for that Capacity Year by the IMO on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years:

- using the indicative mid rates published by the Reserve Bank of Australia; and
- averaged over a 20-trading day period; and

(h) The debt risk premium, *DRP*, for a Capacity Year is a margin above the risk free rate reflecting the risk in provision of debt finance. This will be estimated by the IMO as the margin between the observed annualised yields of Australian corporate bonds which have a BBB (or equivalent) credit rating from Standard and Poors and the nominal risk free rate.

The IMO must determine the methodology to estimate the *DRP*, which in the opinion of the IMO is consistent with current accepted Australian regulatory practice.[1]

[1] Given observed issues with Bloomberg data, the ERA adopted an alternative 'Bond-Yield Approach' to establishing the DRP in its Final Decision on revisions proposed by WA Gas Networks (WAGN) to the access arrangement for the Mid West and South West gas distribution systems. It is understood that WAGN is appealing the use of this method to the Australian Competition Tribunal. Pending the outcome of the appeal, and if the 'Bond-Yield Approach' were to become accepted Australian regulatory practice, the IMO intends to amend this Market Procedure.

(i) If there are no Commonwealth Government bonds with a maturity of 10 years on any day in the period referred to in step 2.9.7(g), the IMO must determine the nominal risk free rate by interpolating on a straight line basis from the two bonds closest to the 10 year term and which also straddle the 10 year expiry date.

(j) If the methods used in step 2.9.7(i) cannot be applied due to suitable bond terms being unavailable, the IMO may determine the nominal risk free rate by means of an appropriate approximation.

(k) *i* is the forecast average rate of inflation for the 10 year period from the date of determination of the WACC. In establishing a forecast of inflation, the IMO must have regard to the forecasts of the Reserve Bank of Australia and, beyond the period of any such forecasts, the mid-point of the Reserve Bank's target range of inflation.

2.9.8 The CAPM must use the following parameters as variables each year.

CAPM Parameter	Notation/Determination	Review Frequency	Value
Nominal risk free rate of return (%)	R_f	Annual	TBD
Expected inflation (%)	i	Annual	TBD
Real risk free rate of return (%)	R_{fr}	Annual	TBD
Market risk premium (%)	MRP	5-Yearly	6.00
Asset beta	β_a	5-Yearly	0.5
Equity beta	B_e	5-Yearly	0.83
Debt risk premium (%)	DRP	Annual	TBD
Debt issuance costs (%)	d	5-Yearly	0.125
Corporate tax rate (%)	t	Annual	TBD
Franking credit value	γ	5-Yearly	0.5
Debt to total assets ratio (%)	D/V	5-Yearly	40
Equity to total assets ratio (%)	E/V	5-Yearly	60

2.10 Determination of the Maximum Reserve Capacity Price

2.10.1 The IMO must use the following formulae to determine the Maximum Reserve Capacity Price:

MRCP = (ANNUALISED_FIXED_O&M + ANNUALISED_CAPCOST / CC)

Where:

MRCPis the Maximum Reserve Capacity Price to apply in a Reserve Capacity Auction;

ANNUALISED_CAPCOST is the CAPCOST, expressed in Australian dollars, annualised over a 15 year period, using a Weighted Average Cost of Capital (WACC) as determined in step 2.9;

CC is the expected Capacity Credit allocation determined in conjunction with Power Station costs in step 2.3.1 (c);

CAPCOST is the total capital cost, expressed in million Australian dollars, estimated for an open cycle gas turbine power station of capacity CAP; and

ANNUALISED_FIXED_O&M is the annualised fixed operating and maintenance costs for a typical open cycle gas turbine power station and any associated electricity transmission facilities determined in step 2.5 and expressed in Australian dollars, per MW per year.

The value of CAPCOST must be calculated as:

$$CAPCOST = ((PC \times (1 + M) + TC) \times CC + FFC + LC) \times (1+ WACC)^{\wedge 1/2}$$

Where:

PC is the capital cost of an open cycle gas turbine power station, expressed in Australian dollars per MW as determined in step 2.3 for that location;

M is a margin to cover legal, approval, financing and other costs and contingencies as detailed in step 2.8;

TC is the estimate of Total Transmission Costs as determined in step 2.4;

CC is the expected Capacity Credit allocation determined in conjunction with Power Station costs in step 2.3.1 (c);

FFC is the Fixed Fuel Cost as determined in step 2.6;

LC is the Land Cost as determined in step 2.7; and

WACC is the Weighted Average Cost of Capital as determined in step 2.9.

2.10.2 Once the IMO has determined a revised value for the Maximum Reserve Capacity Price, the IMO must publish a draft report describing how it has arrived at the proposed revised value and undertake consultation in accordance with clause 4.16.6 of the Market Rules. In preparing the draft report, the IMO must include details of how it has arrived at any proposed revised values for the Annual and 5 Yearly components used in calculating the WACC.

2.10.3 The IMO must publish any supporting consultant reports with the draft report on the Market Web-Site.

2.10.4 After considering any submissions on the draft report the IMO must propose a final value for the Maximum Reserve Capacity Price and submit the report to the Economic Regulation Authority (ERA) of Western Australia for its approval under clause 2.26.1 of the Market Rules.

2.10.5 Once the final value for the Maximum Reserve Capacity Price, with any updates, has been approved by the ERA, the IMO must publish the final report and submissions as required by clause 4.16.7 of the Market Rules.

2.10.6 The IMO must include the Maximum Reserve Capacity Price in the Request for Expressions of Interest document which must be published by the date and time specified in clause 4.1.4 of the Market Rules.

2.11 Major Review

2.11.1 In accordance with clause 4.16.9, the IMO must conduct a review of this Market Procedure containing the methodology used to determine the Maximum Reserve Capacity Price at least once every five years ("Major Review"). This process will include a review of the basis for determining the Maximum Reserve Capacity Price, the structural methodology by which the Maximum Reserve Capacity Price is computed each year and the method the IMO uses to estimate each of the constituent components of the Maximum Reserve Capacity Price.

2.11.2 In conducting the annual review of the WACC, where the IMO considers that any of the comparator companies used in the most recent Major Review are no longer available or that their characteristics have significantly changed, the IMO may select a different set of comparator companies for determination of relevant WACC parameters, applying the following criteria:

(a) the company must be a power generator, energy transmitter or distributor;

(b) market capitalisation must be more than $200m AUD; and

(c) the company must be listed on Bloomberg.